PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

March 12, 2015 GA2014-34

Mr. Jimmie Cho, Senior Vice President
Southern California Gas Company
Gas Operations and System Integrity
555 W 5th Street, GT21C3
Los Angeles, CA 90013

Subject: General Order (GO) 112-E Gas Inspection of San Diego Gas & Electric Company's, Miramar District, Transmission and Distribution facilities

Dear Mr. Cho:

On behalf of the Safety and Enforcement Division (SED) of the California Public Utilities Commission (Commission), Kan Wai Tong, Aimee Cauguiran, Quang Pham, Alin Podoreanu, Joel Tran, and Banu Acimis conducted a GO 112-E inspection of San Diego Gas & Electric Company's (SDG&E), Miramar District (District), Transmission and Distribution facilities from March 10-14, 2014 and from March 18-20, 2014.

SED reviewed the district's gas distribution and transmission system operations and maintenance records for the period of 2012-2013 and conducted field inspections.

A Summary of Inspection Findings (Summary), which contains SDG&E's internal review findings that were presented to SED prior to beginning the audit, SED identified Areas of Violations, Areas of Concern and Recommendations, and Field Observations, is included as an attachment to this letter.

Please provide a written response indicating the corrective actions, and preventive and mitigative measures taken by SDG&E to address the probable violations, areas of concerns and recommendations, and field observations within 30 days from the date of this letter.

Pursuant to Commission Resolution ALJ-274, SED will notify SDG&E of the enforcement actions it plans to take in regard to each of the violations found during the audit after it has an opportunity to review SDG&E's response to the findings included in the Summary.

For any questions related to this matter, please contact Banu Acimis at (916) 928-3826 or by email at banu.acimis@cpuc.ca.gov.

Sincerely,

Kenneth A. Bruno

Kenneth Bruno, Program Manager
Gas Safety and Reliability Branch
Safety and Enforcement Division
California Public Utilities Commission

Summary of Inspection Findings

SDG&E Internal Audit Findings

Prior to SED's inspection of SDG&E's Miramar District records and field inspection, SDG&E provided SED with the results of its internal review audit. During the inspection, SED discussed the details of SDG&E's internal findings and reviewed related records as listed below.

Please inform SED of SDG&E's all preventive and mitigative (P&M) measures taken to prevent similar deficiencies in SDG&E's gas pipeline system.

SDG&E Exceptions Self-Disclosed at CPUC Audit Nov. 2012

1. Dec. 2011, during routine Leak Survey a 2" steel main operating at 55psig, was discovered and verified as not being on our current Bridge & Span inspection program. The span was inspected and has been added to our SAP W.M. system as Bridge/Span #50.

2. May 2012, using new GIS based CP trace capabilities, discovered ~700' of 2" steel main (55psig) to be unprotected. Corrective action was to install 2ea 32 lb. mags and create new CP Mag Anode Area.

3. July 2012, using new GIS based CP trace capabilities, discovered ~412' of 3" steel main (55psig) to be unprotected. Remediation was to replace steel main with poly which was completed Nov. 2012.

4. July 2012, using new GIS based CP trace capabilities, discovered ~1250' of 2" steel main (55psig) and ~171' of 1" steel service (55psig) to be unprotected. Remediation included installing mag anodes on the 2" main and replacing the 1" steel service with poly.

5. Sept. 2012, during routine Leak Survey a 3" steel span operating at 55psig, was discovered and verified as not being on our current Bridge & Span inspection program. The span was inspected and has been added to our SAP W.M. system as Bridge/Span #51.

6. Oct. 2012, using new GIS based CP trace capabilities, 2 steel main segments were discovered as not being in the SAP W.M. system. The first segment, ~536' of 2" steel (55psig) was found to have mag anodes installed but it had not been established as a Mag Anode CP Area in the W.M. system. The second segment, ~576' of 2" steel (55psig) was also discovered to have mag anodes installed but it had not been established in our W.M. system. It should be noted that upon investigation both segments had current CP reads that were within tolerance parameters. Each segment has been established in SAP as a Mag Anode CP Area.

7. Oct. 2012, during routine Leak Survey a 2" steel span operating at 55psig, was discovered and verified as not being on our current Bridge & Span inspection program. The span was inspected and has been added to our SAP W.M. system as Bridge/Span #52.

8. Oct. 2012, during routine Leak Survey a 1.5" steel span operating at 55psig, was discovered and verified as not being on our current Bridge & Span inspection program. The span was inspected and has been added to our SAP W.M. system as Bridge/Span #53.

9. Oct. 2012, during routine Leak Survey a 2" steel span operating at 55psig, was discovered and verified as not being on our current Bridge & Span inspection program. The span was inspected and has been added to our SAP W.M. system as Bridge/Span #54.

   Note: regarding newly discovered Bridge/Span locations. The overriding reason for the newly discovered locations is due to moving the responsibility for inspections from our System Protection work group to our Leakage Mitigation work group. The Leakage Mitigation Patrollers were trained and instructed on the inspection process and instructed to question and verify field locations that they were uncertain if the site was part of our current annual inspection program.

SDG&E Exceptions Self-Disclosed at CPUC Audit July 2013

1. Dec. 2012, in route to a routine Leak Survey a 4" steel span operating at 55psig was discovered and verified as not being on our current Bridge & Span inspection program. The span was inspected and has been added to our SAP W.M. system as Bridge/Span #55.

2. Dec. 2012, as a result of continuing GIS CP trace activities a ~120' 1.5"steel main and ~140' .75" steel service were discovered to be unprotected. Remediation was to install a 17 lb. mag anode and add the segments to SAP as a Mag Anode CP Area.

3. Dec. 2012, during a routine ACOR inspection a 2" steel span operating at 55psig was discovered and verified as not being on our current Bridge & Span inspection program. The span was inspected and has been added to the SAP W.M. system as Bridge/Span #56.

4. June 2013, during a routine Pipeline Patrol a 2" steel span operating at 55psig was discovered and verified as not being on our current Bridge & Span inspection program. The span was inspected and has been added to the SAP W.M. system as Bridge/Span #57.

Areas of Violations

I- Title 49, Code of Federal Regulations (CFR), §192.201 Required capacity of pressure relieving and limiting stations.

§192.201(a) states in part:

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

On 3/18/2014, SED and SDG&E visited Regulator Station, Facility ID-1212, (R1212) located at San Diego State University (SDDU). Upon arrival SED asked SDG&E personnel to check the pressure set point of the regulator and recorded 80-82 psig. Regulator data sheet showed that pressure set point was 50 psig with a 60 psig MAOP downstream distribution system that consists of approximately 210' feet of 2" steel and PE piping supplying gas to two meter sets.

SED noted that since the downstream MAOP is 60 psig, the as-found pressure downstream of R1212 of 80-82 psig exceeded the MAOP plus 10%; therefore, this was recorded as an overpressure event.

After the discovery of the overpressure condition, the regulator station technicians blew down the pressure of the affected segment of the distribution piping to below 60 psig in about 2 minutes. SED also noticed a discrepancy between GIS and the SAP which showed an inlet MAOP of 375 psig and 400 psig respectively.

SED noted that since the regulator failed to lock up, SDG&E personnel decided to tear it down to find out the cause and discovered that the regulator diaphragm was not working properly, see Photo-1, failed diaphragm, and changed it with a brand new one. Consequently, SDG&E leak surveyed the affected segment and found a small fuzz leak at one of the two meter set assemblies (MSA) and repaired it prior to leaving the site and SDG&E put the regulator station back in service on the same day. On 3/19/2014, SDG&E performed a second leak survey of the affected facilities and did not find any other leaks.

SDG&E informed SED that SDG&E performed further evaluation of the components and downstream distribution system. SDG&E conducted another follow-up leak survey on March 27, 2014 and did not find any leaks. SDG&E indicated that Region Engineering evaluated the possibility of installing an electronic pressure recorder with a signaling device on one of the MSAs downstream of R1212 at SDSU.

SED also noted that prior to this event; SDG&E experienced another overpressure event at the same regulator station due to human error on April 1, 2013.

Photo 1- Close up view of the failed diaphragm of the regulator R1212 at SDSU

Please inform SED of the P&M measures taken to prevent similar failures in the future.

II- Title 49, CFR, §192.465 External corrosion control: Monitoring.

192.465 (a) states:

"(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period."

SED reviewed SDG&E's corrosion control records including Cathodic Protection Area (CPA) maps and discovered that a 5-foot section of isolated steel on CPA map 157 located at 4775 Lamont Street was not part of SDG&E's CP10 program. SDG&E failed to monitor this isolated steel pipe segment as required.

Please provide details of SDG&E's plan to locate all other unmonitored pipeline sections in its system.

III- Title 49, CFR, §192.513, Test requirements for plastic pipelines.

§192.513 states in part:

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test.

(d) During the test, the temperature of thermoplastic material may not be more than 100 F (38 C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

During the review of SDG&E pressure test records, SED found that SDG&E did not record the temperature of its plastic pipelines in its pressure test records; therefore, SDG&E failed to comply with the requirements of §192.513.

After the inspection, SDG&E provided SED with a gas standard, D7725, section 4.1.6, which states:

"The PE pipe temperature shall not exceed 140 F during the testing in accordance with 192.513(d). Measures such as covering the pipe with acceptable shading material should be taken to reduce and/or maintain the PE pipe temperature below 100 F."

SED noted that this gas standard defines the temperature limits on the plastic pipelines. However, it does not address how SDG&E monitors and records the temperature changes during the pressure tests.

Additionally, SDG&E must ensure that piping being tested does not exceed the maximum temperature at which it has been qualified as indicated by the marking on the pipe and fittings. SDG&E should also consider the influence of ambient, test medium, and ground temperatures that can affect the pipe temperature during a test since sunlight may significantly elevate the pipe temperature, and black plastic pipe can exceed 140 F (60 C) temperature when exposed to direct sunlight.

Please also note that according to American Society for Testing and Materials (ASTM) D 2513 requirement, the manufacturers mark the pipe and fittings with the maximum temperature at which the pipe and fittings have been qualified for use.

Therefore, SED determined that SDG&E must record the temperature during pressure tests of its plastic pipelines and add the temperature monitoring requirement in its standard. SDG&E must also communicate the changes to the standard which affects the covered task to all its affected personnel who perform the covered task, and re-qualify the affected personnel as necessary.

Please inform SED of the corrective actions taken to address the deficiencies identified above and provide SED with an updated version of the standard. Additionally, please indicate the date when SDG&E plans to complete the re-qualification and the number of personnel to be qualified and provide training records once they are completed.

IV- Title 49, CFR, §192.517 Records.

§192.517 states in part:

"(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§192.505 and 192.507. The record must contain at least the following information:

(6) Elevation variations, whenever significant for the particular test."

SDG&E's Company Operations Standard G7369, Hydrostatic Test Requirements states in part:

"6.1: …Pipe elevations are required when test pressure is 1200 psig and elevation change is greater than 100 feet or required for all tests when specified test pressure is greater than 1200 psig…"

Additionally, SDG&E Gas Standard G7365, Pneumatic Test Requirement for Pipelines Operating above 60 psig states in part:

"…6. RECORDS
6.1. All the records for pipelines tested at or above 100 psig shall be retained for the life of the pipeline. Each record must contain the following information that may be written on the back of the pressure recording chart:

6.1.9. Elevations of pipe are required when the test pressure is 1200 psig and elevation change is greater than 100 feet.

6.1.10. Elevations of pipe are required for all tests when specified test pressure is greater than 1200 psig…"

During the inspection, SED reviewed SDG&E pressure test records and noted that both Standards G7365 and G7369 require taking the elevation differences into consideration when the elevation change is greater than 100 ft. **and** if the test pressure is 1200 psig or higher. However, §192.517 does not define any specific test pressures for operators in order to consider elevation changes during testing.

SED discussed how SDG&E accounts for differences in elevations during the inspection and based on the explanation received. SED understands that SDG&E also calculates and considers static head due to changes in elevations for test pressures below 1200 psig and elevation changes of less than 100 ft. However, SDG&E standards describe the requirement differently.

Please explain SDG&E's technical justification of considering only elevation differences of 100 ft. or higher for test pressures greater than 1200 psig.

SED determined that SDG&E must revise its standards to add the requirement of taking the elevation differences into consideration for test pressures not only greater than 1200 psig but also less than 1200 psig during testing of its pipelines and must also record elevation changes for less than 100 ft.

Please provide SED with a copy of the revised standards and explain how SDG&E plans to train its affected employees to inform them about the pressure test requirement change in its Standards in terms of recording elevation changes during testing. Additionally, please indicate the date when SDG&E plans to provide necessary training for its affected personnel in order to communicate the changes to the standards and provide training records once they are completed.

V- Title 49, CFR, §192.605 Procedural manual for operations, maintenance, and emergencies.

§192.605 (a) states in part:

"(a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response…"

SDG&E Standard G8159, Distribution Pressure Regulating and Monitoring Station & Vault – Inspection, Maintenance and Settings requires that all station valves are exercised during annual station maintenance.

SED reviewed Fallbrook PLS work order for Non-DOT valve inspection record and noted that SDG&E did not include the Station 1-inch ball valve located downstream of the diffuser as being maintained during station maintenance.

Furthermore, SDG&E's Transmission Standard, T8167, Valve Inspection and Maintenance, describes the inspection and maintenance procedures and requirements for CPUC/DOT valves and non-CPUC/DOT valves. It further states that maintenance of non-CPUC/DOT valves takes into account existing procedures and the inspections of these valves and valve-related equipment are scheduled, tracked, and documented using an approved computerized scheduling and tracking system.

During the inspection, SDG&E District personnel stated that the 1" ball valve was a redundant valve to the ball valve installed upstream of the diffuser; thus, it is believed that the downstream valve does not need to be maintained.

Although SED understands that the 1" ball valve downstream of the diffuser may be a redundant valve, SED believes that it must still be maintained per company standards and, at a minimum, checked for proper sealing.

Please inform SED of the remedial actions taken to address this deficiency.

VI- Title 49, CFR, §192.605 (a) General

SED found that SDG&E's transmission valve (plug valve) training module used to train and qualify its personnel to perform valve inspection and maintenance covered task was not consistent with descriptions written on its work orders. According to the training module, SDG&E personnel need to lubricate the plug valves at every inspection. However, this instruction was not available to the field personnel during our field inspection. SDG&E personnel only had access to its work order and valve inspection gas standard.

SED also noted that none of these SDG&E documents specified the lubrication requirement on every plug valve inspection. Instead, the work orders only called for the lubrication of the plug valves as necessary. SED determined that SDG&E failed to have the training module available to its crew during inspections and maintenance activities.

After the inspection, SDG&E made the training module available to the field crew by adding the intranet access on their laptops. However, SDG&E still has not addressed how the work orders and associated gas standards would be revised to cohere with the training module and how to share the revised documents with its field crew.

Please provide SED with a revised copy of the standards and the training material.

VII- Title 49, CFR, §192.605 (a) General

SDG&E's Gas Standard G8159 states in part:

"5.8. Verify the station piping schematics are correct.
5.9. Report discrepancies in piping schematics and station components to Supervisor and take corrective action."

SED reviewed SDG&E's pressure regulator station records and identified several discrepancies between station schematics and the SAP Inspection work orders. SDG&E did not maintain accurate schematics for the following regulator stations:

1. **REG-GS.SDG.BCH.RS.1523**
   SAP Inspection #510000161685 dated 2/7/12 shows the worker regulator pilots as Fisher 161-EB series; however, the station schematic shows the pilots as Mooney Series 20.

   SED noted that SDG&E corrected all discrepancies between the SAP work orders and schematics that SED identified during the inspection.

2. **REG-GS.SDG.CMT.RS.1502**

SAP Inspection #510000174012 dated 8/12/13 shows an outlet MAOP of 400 psi; however, the station schematic shows an outlet MAOP of 55 psi.

3. **REG- GD. SDG.NRE.RS.1516**
   SAP shows an inlet MAOP of 640 psi; however, the station schematic shows an inlet MAOP of 800 psi.

4. **REG- GD. SDG.NRE.RS.1500**
   SAP shows an inlet MAOP of 640 psi; however, the station schematic shows an Inlet MAOP of 800 psi.

5. **REG- GD.SDG.CMT.RS.1491**
   a. SAP shows an inlet/outlet MAOP of 400/60 psi; however, the station schematic shows an inlet/outlet MAOP of 375/55 psi.

   b. SAP Inspection #510000182188, dated 11/6/12 shows the monitor regulator pilot as a Mooney Series 20; however, the station schematic shows the pilot as a Fisher EZR.

6. **REG- REG-1435, Distribution Regulator Station**, found in the field on 3/19/14, Outlet MAOP on the Schematic (10 psi) does not match the MAOP in their SAP records (5 psi).

   Please inform SED of the corrective actions taken to address the deficiencies identified above.

VIII- Title 49, CFR, §192.605 (a) General

SDGE's Gas Standard G8159: Distribution Pressure Regulating and Monitoring Station & Vault – Inspection, Maintenance, and Settings – Section 5.12 Inspection Guide states:

"Check monitor operation open, close and lock-up pressures."

SED reviewed maintenance records for regulator station #73 – Ardath & La Jolla Shores and discovered the following abnormal operating conditions (AOCs) that SDG&E personnel did not recognize during the maintenance performed on 4/15/12:

1. The upstream pressure was discovered to be lower than the usual; the upstream pressure was recorded as 185 psig. The upstream MAOP is 400 psig with an MOP of 290 psig. The upstream pressures found in 2010 and 2011 were 232 psig and 210 psig respectively.

2. The recorded lockup pressure of the first stage pilot regulator, Grove 829, was equal to the "as found" upstream pressure of 185 psig.

3) The recorded first stage pilot regulator lockup pressure of 185 psig which was 35 psi above the set point of 150 psig.

Please inform SED of the P&M measures taken to address this deficiency.

IX- Title 49, CFR, §192.605 (a) General SDGE's Gas Standard G8138: Optical Methane Detector (OMD) Operation and Maintenance states:

"1.4. Quarterly External Calibration Check on the OMD is performed and recorded by the Gas Instrument Shop Miramar.."

SDGE's Gas Standard G8189: Heath Detecto-Pak III, Flame Ionization Gas Detection Unit states:

"1.3. The Detecto-Pak III shall be calibrated after 90 days but not to exceed 120 days.

SED reviewed SDG&E's instrument calibration records and noted that SDG&E failed to follow its instrument calibration requirements for the following instruments listed in Table 1:

Table 1- Instruments that were calibrated late

Instrument Type - Model	Serial #	Calibration Date	Next Calibration Date	Maximum allowed calibration Interval
OMD	2501040-5	1/14/11	7/7/11	quarterly
FI-DP3	#145	6/23/11	11/11/11	90 days not to exceed 120 days
FI-DP-3	9738-5	1/10/11	5/18/11	90 days not to exceed 120 days
FI-DP-3	9738-5	6/24/11	11/9/11	90 days not to exceed 120 days
FI-DP-3	8455-3	2/10/10	8/19/10	90 days not to exceed 120 days
FI-DP-3	9737-5	6/23/11	11/9/11	90 days not to exceed 120 days

Please inform SED of the P&M measures taken to address these deficiencies.

X- Title 49, CFR, §192.605 Procedural manual for operations, maintenance, and emergencies.

§192.605 (b) states in part:

"(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations. Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part…"

Title 49, CFR, §192.745 Valve maintenance: *Transmission*

"(a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year."

Title 49, CFR, §192.747 Valve maintenance: Distribution systems.

"(a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year."

SDG&E's Valve Inspection and Maintenance standard does not explicitly describe the procedure used for performing maintenance for different types of valves. For instance, Valve Inspection and Maintenance SDG&E's Standard, T8167, generally states that the valve must be "partially operated"; however, partial operation of a plug valve can be different from partial operation of a gate valve. SDG&E provided a copy of the training module for SDG&E OQ tasks 16.2 and 16.3 for inspecting and maintaining transmission and distribution valves. The training module does not explicitly describe "partial operation" of the various types of key valves.

SED reviewed SDG&E's transmission and distribution valve maintenance related documents and determined that there are three sources of information for field personnel:

1. Valve maintenance standard
2. Valve maintenance instructions/training module
3. Valve maintenance work order

Field personnel explained to us that they were trained in the field and learned how many turns each type of valve requires in the field. However, this information is not provided to them in a written format.

Examples of field observations for this issue:

- SED and SDG&E visited the Regulator Station 1515 located 30th and D Street. SDG&E personnel exercised the 6-in. ball valve, number 20293 and explained that this type of valve could be a quarter turn or multi turn depending on the configuration. SED did not find any specifics about how many times that particular valve needs to be turned in order to partially operate in the work order nor in SDG&E's procedures.

- SED and SDG&E visited the regulator station 1212 located at SDSU and exercised the inlet fire valve, # 2584, at the station. But the maintenance request/work order that was completed for this valve on 5/13/13 recorded the type of valve as NV, Nord Valve. However, neither SDG&E's valve maintenance standard nor the training module mentioned this type. After discussion with the maintenance crew, we found out that this was actually a brand name not type of valve and it was a plug valve. The work order also did not specify the number of turns for this type of valve.

- Similarly, NV type of valve was recorded on the maintenance sheet for Distribution Valve 1481 and the work order did not specify the number of turns for this type of valve.

SED noted that crews did not have any written guidance document about the number of turns to partially operate or service each type of valve. The type of valve is recorded on the maintenance work order; however, neither the valve station maintenance sheet nor the valve maintenance standard describes how they need to be exercised.

SDG&E must update its standard, procedures, and training documents to include the valve maintenance and exercise requirements for each type of valve by clearly defining "partial operation and service" of all possible types of valves used in its transmission and distribution system.

SED must also train its personnel who perform the Valve Maintenance/Inspection covered tasks after the new information is added to the training module and standard.

SED also noted that it would be also helpful for the field personnel to have this information on the work order that is given to them for the inspection and maintenance.

Please inform SED of the corrective actions taken to address the deficiencies identified and provide SED with a copy of the revised Valve Inspection and Maintenance standard and related training programs. Additionally, please indicate the date when SDG&E plans to provide necessary training for its affected personnel in order to communicate the changes to the standards and provide training records once they are completed.

XI- Title 49, CFR, §192.739 Pressure limiting and regulating stations: Inspection and testing.

§192.739 states in part:

"(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a)"

SED reviewed SDG&E Standard G8159, Distribution Pressure Regulating and Monitoring Station & Vault – Inspection, Maintenance and Settings and noted that Sections 5, 5.11 and 5.12 require field personnel to check station lock-up and monitor lock-up pressures. However, SED found that SDG&E procedures do not define lock up or how pressure control valves (PCV) lock up is verified in the field.

SDG&E Gas Transmission Inspection Work Order #4506146 (Mission Gate Station) dated May 15, 2012 indicated the following recorded pressure values:

PCV2: Set Point = 305 psig, Lock Up = 305 psig
PCV4: Set Point = 310 psig, Lock Up = 310 psig

During the field inspection, SED noted that lock up pressures for PCVs were recorded as the set point pressures and not the downstream "lock up" pressures. SED also found that as part of the annual inspection process, SDG&E used the high pressure positioner top and bottom gauges to verify the PCV's fully closed and sealed. If SDG&E records lock up as part of the inspection process it must revise its procedures to define lock up and state how it is verified in the field. If an alternative pressure positioner procedure is used to ensure compliance with §192.739, SDG&E must incorporate this into its standards.

Please inform SED of the corrective actions taken to address the deficiencies identified and provide SED with a copy of the revised standard and related training programs. Additionally, please indicate the date when SDG&E plans to provide necessary training for its affected personnel in order to communicate the changes to the standards and provide training records once they are completed.

XII- Title 49, CFR, §192.745 Valve maintenance: Transmission lines.

"(a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year."

Title 49, CFR, §192.747 Valve maintenance: Distribution systems.

"(a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year."

On February 10, 2012, SDG&E notified the CPUC and the other local authorities that SDG&E inspected 31 valves located in the City of San Diego about three months after the compliance window. SDG&E also informed the director of SED (formerly CPSD) that late inspections occurred due to data error in company's new maintenance and management system designed to schedule inspection of its facilities. After the discovery, SDG&E completed all inspections and took additional measures to prevent similar occurrences in the future.

In addition to the 31 valves that were inspected late, SED also found that there were seven more valves that were inspected outside the compliance window in 2012. SDG&E discovered the late inspections of these valves in May 2012; however, it did not notify the Director of SED nor the other affected local authorities about the late valve inspections.

The late inspected valves are as follows:

Valve #s: 1196, 7142, 7143, 7144, 7145, 7149, 7150

Resolution ALJ-274 Appendix A states in part in regards to Self-Identified Notifications: E. Notification of Local Authorities

1. As soon as is reasonable and necessary, and no later than ten days after service of a citation is effected, each respondent gas corporation shall notify the Chief Administrative Officer or similar authority in the city and county where a citation is issued, and within ten days of such notification shall notify the Director of CPSD that the local authorities have been notified by serving an affidavit that lists the date of notification and the name and contact information of each local authority so notified.

According to ALJ-274 decision, SDG&E should have done the following:

1. According to E. Notification of Local Authorities, SDG&E should have notified the local authorities of the additional seven valves which were inspected outside compliance window, and

2. Per E of ALJ-274, Appendix A, SDG&E should have notified the Director of CPSD that the local authorities have been notified by serving an affidavit that lists the date of notification and the name and contact information of each local authority so notified.

Please inform SED of the preventive measures taken to address this deficiency.

Areas of Concern and Recommendation

I- SED noted the following missing information in SDG&E records:

1. REG-1502

SAP Inspection #510000174012 records dated August 13, 2013 shows the inspection was conducted by an unknown individual as recorded in the "completed by" field.

SDG&E provided field records that indicated the inspection was conducted by qualified field technicians. SDG&E suspected that the unknown name was caused by a data entry error on the SAP work order.

2. REG- GD.SDG.CMT.RS.1466

SAP Inspection #510000170768 records dated July 9, 2012 is missing the name of the employee who conducted the inspection in the "Completed By" field.

SDG&E provided field records that indicated the inspection was conducted by qualified personnel.

3. REG- GD.SDG.CMT.RS.963

SAP Inspection #510000166481 records dated May 11, 2012 is missing the name of the employee who conducted the inspection in the "Completed By" field.

SDG&E provided field records that indicated the inspection was conducted by qualified personnel.

SED recommends that SDG&E maintain complete and accurate records in its SAP system.

II- SDG&E Gas Standard G7809, Qualification and Re-qualification of Welders describes the requirements for qualification and re-qualification of welders that will be performing joining operations on SDG&E steel pipeline.

Section 2.2 of G7809 states:
"Gas Operations Services – Welding Training maintains an up-to-date list on its website of all qualified personnel within the Company and Company Contractors. However, it is the responsibility of each welder to ensure their welding qualification(s) do not expire."

SED reviewed this standard and noted that Section 2.2 waives SDG&E's responsibility of monitoring its welders' qualifications; therefore, SED disagrees with SDG&E's approach. Since SDG&E administrates its qualification program for its employees and contractors' employees, it must be responsible for verifying its welders' continued qualifications.

SDG&E must assure that all its employees and contractors are qualified to perform joining operations on SDG&E steel pipeline prior to assigning related tasks and also verify that previously qualified welders remained qualified.

After the inspection, SDG&E modified its related standard and informed SED that the revised language would be as follows:

"Gas Operations Services – Welding Training maintains an up-to-date list on its website of all qualified personnel within the Company and Company Contractors. However, it is the responsibility of each welder

and the Company to ensure their welding qualification(s) do not expire, except when the welder is performing job functions other than welding."[Emphasis added]

Please provide SED with a copy of the revised standard.

III- SDG&E Gas Standard G7809, Qualification and Re-qualification of Welders, Section 5.1, states:

"Gas Operation Services – Welding Training shall keep records of welding tests and qualified welders."

SED noted that SDG&E standard does not specify the duration of record keeping for welder qualification records.

After the inspection, SDG&E modified its related standard and informed SED that the revised language would be as follows:

"Gas Operation Services – Welding Training shall keep records of welding tests and qualified welders for the life of the asset."

Please provide SED with a copy of the revised standard.

IV- SED noted that some of the SDG&E critical valves installed on its transmission systems could be operated by its own system gas pressure or manually by hydraulic hand pumps. During the inspection, SDG&E field personnel explained that the hydraulic fluid is kept in reservoir and a certain level of hydraulic fluid needs to be maintained, so that a valve operator can pump enough fluid into the system and turn the valve during a routine inspection. However, neither SDG&E nor the pump manufacturer defined the minimum quantity of hydraulic fluid needed to ensure proper operation of the hand pumps. SED noted that SDG&E field personnel checked the fluid level with a metal stick. SED recommended SDG&E contact the manufacturer and develop a measurable method to determine the minimum level of fluid in the reservoir for proper operation of the hand pumps.

During the inspection, SDG&E contacted the hydraulic pump manufacturer who advised SDG&E that the minimum fluid level should be 1/3 level during normal operation. The manufacturer also added the new requirement into it hydraulic actuators manual.

Please provide SED with a copy of the revised standard and copy of the training records provided to affected personnel who perform related covered tasks.

V- SED reviewed SDG&E's After Action Reports of Major Gas Incident Functional Exercises conducted on 9/7/11 and 11/30/12 and list of participants from the management.

SED recommends that SDG&E should also keep a list of all field personnel who participate such exercises and their job functions/responsibilities that they perform as part of the Emergency Exercises and Drills.

VI- SED noted that the schematic for regulator station: Reg-933, located So. Interstate, East of Fairmont Ave., needs to be updated by removing # 11, ¼" Fisher 161.

VII- SED reviewed SDG&E's "Pipe Leak, Condition, and Maintenance Report" for transmission leak surveys and findings, and SED noted that SDG&E crews did not record the percent gas or percent LEL data on these reports.

Further analysis of the leak form also showed that when the leaks are first discovered, there is no field on the form to record such data other than “recheck for gas” field which is noted on the back side of the form.

SED is concerned that SDG&E may not be able to prioritize leaks without actual gas leakage percent information since SDG&E Company Operations Gas Standard, G8135, Leak Classification and Mitigation Schedules refers to this information for classification and proper response procedures such as investigation, re-evaluation, and repair.

Please inform SED of the remedial actions taken to address this deficiency and provide SED with a copy of the revised leak survey forms.

VIII-Line 1600 MAOP Exceedance: On August 15, 2012, a segment of SDG&E’s Line 1600 experienced pressure excursion. SDG&E investigation summary indicated that its employees incorrectly tagged and operated the sensing line valves. SDG&E root-cause analysis indicated that Southern California Gas Company (SoCalGas) employees from Beaumont District incorrectly operated normally opened sensing line valves tied into SoCalGas’s Lines 1027 and 1028 pressure limiting control valves that fed SDG&E Line 1600 at the Rainbow Compressor Station. The closure of the incorrectly tagged sensing line valves caused SoCalGas’ Lines 1027 and 1028 pressure limiting control valves to sense lower pressure downstream and automatically compensated for the lower pressure by introducing more gas at pressures of 683 psig and 660 psig respectively into Line 1600 at the Rainbow Compressor Station. Line 1600 established Maximum Allowable Operating Pressure (MAOP) is 640 psig. The inadvertent introduction of gas pressures ranging from 660 to 683 psig into Line 1600 resulted in the exceedance of its established MAOP. This pressure excursion of 683 psig translates to a 6.7% pressure increase above the Line 1600 established MAOP. SDG&E performed an In-Line inspection few months after the event.

SED is concerned about the factors that led to this event and the subsequent actions that were taken after the event. First, there was no evidence of Operator Qualification (OQ) revocation or retraining of the employee that mislabeled or incorrectly tagged the sensing line valves and the employee that operated the sensing line valves. Secondly, there was no evidence of Drug and Alcohol testing of the employees involved. Even though this event did not meet reportable incident criteria, SDG&E should have considered it as a near miss event and taken some actions accordingly.

SED determined that in addition to the corrective actions SDG&E identified in its investigation summary and SDG&E should do the following:

1. SDG&E should identify, label and tag all critical valves, pipelines and appurtenances within the Compressor Stations. In addition, update and verify the Station drawings and confirm that the labeling, tagging of valves normal operating positions are accurate and match the actual equipment in the field and MAXIMO equipment identification. SDG&E should perform quality control of the process and the activities routinely and document its findings.

2. SDG&E should establish more stringent and thoroughly reasoned work clearance procedure and practice that will prevent employees from working on any transmission pipeline without Gas Control documented clearance.

   Please explain specifically how SDG&E’s proposed stringent work clearance procedure will prevent recurrence of similar event in future. Please specify what quality control activities that will be implemented to prevent the recurrence.

3. SDG&E should incorporate the lessons learned from this event into its Meters & Regulations (M&R) and Control Room Management (CRM) Operator Qualification training program.

4. Although this event was not a reportable incident, SDG&E should review its Anti-Drug and Alcohol procedures and OQ revocation policy and incorporate lessons learned from this event and others into these procedures and policies. SDG&E should establish and verify that its Wellness Department and Training & Qualification Department are notified of all pipeline events and incidents. Establish clear communication path to ensure complete and accurate assessment of all events or incidents and determine what appropriate testing and re-training is required.

IX- Title 49, CFR Part 192, §§192.473(a) and 192.613(a)

§ 192.473 External corrosion control: Interference currents states:
"(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents."

§ 192.613 Continuing surveillance states:
"(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions."

Alternating Current Influence and Interference on Pipelines

SED reviewed SDG&E Gas Standard, procedure G8037" High Voltage Alternating Current (HVAC) on pipelines" and noted that the Gas Standard G8037 adequately addressed the company's safety policy and practice to protect general public, company personnel or employees involved in construction or O&M work on new or permanently installed facilities (above or below ground) in the High Voltage Alternating Current (HVAC) Influence area. However, SDG&E Gas Standard, procedure G8037 did not provide sufficient consideration to protection of its gas pipelines from fault or stray currents induced by high voltage alternating current (AC) power transmission systems (high voltage transmission lines 69-KV and above) and AC electrified railway systems.
SED is concerned that the existing procedure did not require active testing and monitoring of AC interference or Stray AC influence in areas in which AC interference or influence are suspected such as the high voltage overhead transmission power lines.

SED recommends that SDG&E enhance its Gas Standard procedure to include implementation of a continuing surveillance program to identify, monitor and mitigate alternating current influence on its pipeline. SDG&E should engage its subject matter experts in this field to establish procedures and guidelines for design, construction, operation, and maintenance of its gas pipelines that may be subject to fault or stray alternating currents from high voltage overhead AC power transmission systems, AC electrified railway systems or Lightning.

SED recognized that the regulation does not have stray AC mitigation specifics but recommend that SDG&E's pipeline Corrosion and AC Influence subject matter expert review and incorporate where appropriate research studies endorsed by industry organizations such as National Association of Corrosion Engineers.

X- SED reviewed SDG&E's Line 3600 annual CP records and found that on July 7, 2012, as a result of its an annual CP survey of Line 3600, SDG&E discovered that Electrical Test Stations (ETS) boxes 3600-30-P and 3600-29-P, located on the street, were paved over by a local government agency during a road construction work. SDG&E issued a work order to raise the ETS boxes but needed the local government agency to approve its construction permit to commence the work. SED noted that it took SDG&E approximately six months to complete the work order to raise the ETS boxes in order to take the P/S reads.

P/S readings for CP Areas 3600-29-P and 3600-30-P were recorded on 6/4/11 and they were scheduled to be taken again in July, 2012; however, due to the ETS not being accessible, the next readings were recorded on 1/14/13. SED determined that SDG&E exceeded 18 months to record the P/S readings.

Although SDG&E provided evidence that it was actively engaged in the permit application process, but SED is concerned that the process could have been expedited. SED recommends that SDG&E implement a mechanism to expedite this process in future.

Please inform SED of the preventive measures taken to address this deficiency.

XI- SED also noted the following issues during the record review and recommended the following:

1. SDG&E should prepare a master list of all Emergency Shut Down (ESD) Valves, ESD Valve Handles, Gas Detectors and UVIR in Rainbow Compressor Stations and Moreno Valley Compressor Stations.

2. SDG&E's Operator Qualification Task ID 6.1 "Tapping Pipelines Under Pressure" should be separated into two pressure categories (Tapping Pipelines Under Low pressure and Tapping Pipelines Under High pressure) to eliminate the current confusion between employees that are qualified for high pressure tap from the ones qualified for low pressure tap.

3. SDG&E should revise its Class Location Study procedure G8121 "Location Class- Determination and Changes" Section 1.3. The current procedure is unclear and ambiguous partly because it merged two sections of Part 192 § 192.609 "Change in class location: Required study" and § 192.611 "Change in class location: Confirmation or revision of maximum allowable operating pressure" into one procedure and the attached table on Section 1.3 did not clearly define required study parameters from the confirmation or revision of MAOP parameters.

4. SDG&E should clearly define how the field data gathered with Form 2112 will be communicated to Pipeline Integrity group and how it will get to its final destination in the High Pressure Pipeline Database.

5. SDG&E should perform a detail root cause analysis on Line 49-107 incident and determine where else that identical equipment and/or material may exist within SDG&E system.

Field Observations

1. On 3/19/14, SED visited the Reg. Station 700 located at Midway and Sports Arena Blvd. Before starting the inspection, SDG&E personnel checked the inlet MAOP for this dual system on GIS and recorded as 375 psig even though the work order created from SAP system showed 400 psig.

   SED noted that there seems to be a discrepancy between the SAP system and GIS for the MAOP information. If the crews are relying on the diagrams and MAOP information from GIS, then GIS needs to be updated with accurate MAOP data and communication between the mapping group and the GIS group should be improved in order to keep accurate data on GIS.

   SED also found that GIS does not show any set points for the worker and monitor regulators. This may be an issue in emergency conditions when there is no work tickets created and GIS is the only source for field crews to obtain pressure set points on-site.

   SDG&E personnel started to inspect the right run and found a fuzz leak in Vault # 3 which was the upstream side where the monitor was. They recorded 6% LEL gas on the travel indicator which is normally in open position. SDG&E repaired the leak by changing the O-ring around the indicator.

   After the leak was repaired, SED observed that set point of the working regulator in Vault # 4 as 89 psig. The lock up pressure was recorded to be initially 91.5 psig, then started creeping up and reached 93.5 psig. SDG&E supervisor asked the crews to troubleshoot by replacing parts of the regulator, after that it achieved good lock up at 91.3 psig.

   At this regulator station, SED also asked the valve maintenance crew to exercise the inlet and outlet valves for this station. SED noted that the work order for the valve maintenance showed the brand name of the valve not the type of valve.

2. During the field visit to Reg. Station 1026, SDG&E recorded 395 psig for inlet MAOP from its GIS; however, it was recorded as 400 psig on the work order. Additionally, GIS did not show any pressure set points for the regulator or the monitor.

3. On 3/19/14, SED verified the installation of the barrier post to protect the meter located at 1338 Amethyst St., San Diego and noted that another barrier post would be necessary to completely prevent any vehicular damage to the meter. SDG&E informed SED that SDG&E installed another barrier post at this location on 3/20/14.

4. On 3/19/14, SED noted signs of atmospheric corrosion on meter set located at 1011 56th St., San Diego. SDG&E informed SED that it took necessary remedial actions by wire brushing and painting the meter set on 3/20/14.

5. On 3/19/14, SED and SDG&E took P/S reading at 3627 Crowell St., San Diego and recorded - 0.418 Volts for the isolated section (10%er). After the discovery of the low P/S reading, SDG&E found out that it was caused by loose connection from the anode to the steel riser. SDG&E supervisor explained that on 9/5/13, SDG&E installed a mag anode at this location and recorded -0.95 Volts. After SDG&E crews tightened the clamp, the reading immediately started to go up, recorded: 0.6 volts. SDG&E explained that long term mitigation action would be to replace it with PE.

   On 4/1/14, SDG&E informed SED that it started the process (SAP # 300000005595) of replacing the service with plastic and installing an anodeless riser at 3627 Crowell Street, San Diego and this job was in the permitting process.

Please inform SED when the corrective action is completed.

6. On 3/19/14, SED and SDG&E visited 10102 Crestside Plaza, Spring Valley and recorded - 0.65 Volts for the isolated section (10%er) as P/S reading. SDG&E supervisor explained that the remedial action would be to install magnesium anode system to bring it up.

   On 4/2/14, SDG&E informed SED that SDG&E installed a 1-lb magnesium anode at 10102 Crestside Plaza on March 21, 2014 and the P/S reading was recorded as -1.54 volts.

7. On 3/20/14, SED and SDG&E conducted field inspection at Distribution Regulator Station 1132 located at 6875 Consolidated Way and noted the following observations:

   - Inlet MAOP: 400 psi
   - Outlet MAOP: 60 psi
   - Upstream, Monitor, As Found: 55.5 psi
   - Downstream, Worker, As Found: 51 psi
   - Crew tested set point (60 psi) and lock up (62 psi) on the Monitor regulator
   - Crew tested lock up and set point on the Worker regulator but could not achieve lock up. After troubleshooting, it was determined that there was sulfur on the stem seat. This stem was replaced with a new one.
   - Crew re-tested the Worker regulator but still could not achieve lock up. The crew determined that they needed to open up the bypass valve to get higher upstream pressure in order to achieve lock up. After troubleshooting, the crew recorded the set point as 56.2 psi and was able to achieve lock up at 59.3 psi.
   - The troubleshooting determined that the Monitor regulator would need to be re-tested for lock up (60.3 psi) and set point (59.3 psi).

   Please inform SED of the P&M measures taken to address the sulfur problem at company regulator stations.